This Agency financial information is provided for discussion purposes during this pre-rate case process.

Pre-Decisional

WP-07 Power Rate Case Workshop

November 01, 2005

Initial Proposal Preview

Table of Contents

Firm Power Products and Services Rate Schedule

- FPS-96R expires at the end of this rate period; FPS-07 is its replacement.
- FPS-96R had a ten-year term (set by its predecessor, the FPS-96 rate schedule); the proposed FPS-07 will have a three-year term.
- Products offered under FPS-07 will be essentially the same as FPS-96R.
- FPS-96 and FPS-96R were proposed as market-based rates but, pursuant to a settlement, implementation of those rates was subject to cost-based limitations.
- Since then the West Coast market has evolved. It is more volatile, complex, and includes more participants; additionally, BPA has much less surplus available for sale. Accordingly, cost-based limitations are no longer needed and BPA is proposing FPS-07 as a true market-based rate that will enable BPA to participate in the market on a level playing field.
- An outside consulting agency evaluated BPA under FERC’s screens for market power and found that BPA passed; this factored into BPA’s decision to propose a true market-based rate.
- When selling under FPS-07, however, BPA proposes to abide by a self-imposed price cap that mirrors the FERC West-wide cap (rising or falling along with that cap). Again, BPA’s aim is to participate in the market on a level playing field.

SECTION 7(b)(2) Rate Test

Loads

- Program Case:
- PF preference and PF exchange loads (including IOU exchange load).
- No direct sales to the DSIs are forecast.
- No sales at the NR rate are forecast.

- 7(b)(2) Case:
- PF preference loads from the Program Case are increased by ~750 aMW due to foregone conservation savings.
- No DSI load served by public body customers

SECTION 7(b)(2) Rate Test

Resources

- Program Case at Load/Resource Balance
- In the 7(b)(2) Case, PF preference customers are served with FBS resources not obligated to other entities under contracts existing as of the effective date of the Northwest Power Act.
- Additional resources brought on from the 7(b)(2) resource stack include BPA annual programmatic conservation and non-dedicated Mid-Columbia resources.
- The rate test model selects the least costly resources first.
- For the 2007 Initial Proposal the resources selected include the non-dedicated Mid-Columbia resources.

SECTION 7(b)(2) Rate Test

DSI Monetary Settlement

- Costs associated with the DSI service benefits are included in both the Program and 7(b)(2) Cases.

Settlement of the REP with the IOUs

- Costs associated with the IOU REP Settlement are excluded from both the Program and 7(b)(2) Cases.
- The IOU REP Settlement costs are brought into the ratemaking process in the Subscription Step after the 7(b)(2) Rate Test is conducted in the Rate Design Step.

SECTION 7(b)(2) Rate Test

Cost of Uncontrollable Events

- There are no costs forecasted for uncontrollable events in the 2007 7(b)(2) Rate Test.
- While there are many unknowns associated with the marketing of power from a primarily hydro generating system, these unknowns are not uncontrollable events.
- Planned Net Revenue for Risk (PNRR) is not a cost of uncontrollable events.
- The reasoned decision process resulting in the termination of generating facilities is not an uncontrollable event.

SECTION 7(b)(2) Rate Test

Overview of the 2007 Initial Proposal 7(b)(2) Rate Test

- The Program Case initially included 12 potential exchanging utilities.
- During the execution of the modeling, all potential exchangers dropped out.
- With no exchange costs there is a small 7(b)(2) trigger.
- The small trigger indicates that about $40 million per year in PF preference rate protection should be reallocated to all other loads.
- With no exchange and no direct sales to DSIs, there are no other loads.
- Therefore, a very small amount of the $40 million is allocated to the token (0.001aMW) PF exchange and IP load through 7(b)(3) and the rest is reallocated back to Public load through 7(a)(1).

- The resultant PF exchange rate is about $70 and the IP rate is about $50.

SECTION 7(b)(2) Rate Test

What if

- While inclusion of the Mid-Columbia resources in the 7(b)(2) resource stack is assumed in the Initial Proposal, the results of the test would be quite different if they were excluded.

- PF exchange rate would be about $43/MWh
- IP rate would be about $38/MWh
- PF preference rate would be about $1/MWh higher than it otherwise would be.

- IOU REP Settlement benefits would be unchanged.

This Agency financial information is provided for discussion purposes during this pre-rate case process.

Revenue Requirement – Income Statement

This table shows the initial proposal revenue requirement income statement with columns comparing the IP with the July revenue requirement workshop. Shading identifies items that have changed since the July workshop.

($000)	A 2007	B Change from July Workshop	C 2008	D Change from July Workshop	E 2009	F Change from July Workshop
1 OPERATING EXPENSES						
2 POWER SYSTEM GENERATION RESOURCES						
3 OPERATING GENERATION RESOURCES	514,139	0	471,856	0	512,425	0
4 OPERATING GENERATION SETTLEMENT PAYMENTS	16,968	0	17,354	0	17,749	0
5 NON-OPERATING GENERATION	9,350	0	5,252	0	2,254	0
6 CONTRACTED POWER PURCHASES	181,652	23,000	150,340	41,626	175,435	66,721
7 RESIDENTIAL EXCHANGE/IOU SETTLEMENT BENEFITS	301,000	(22,000)	301,000	(22,000)	301,000	(22,000)
8 RENEWABLE AND CONSERVATION GENERATION	103,011	(35)	107,873	(32)	129,547	(26)
9 TRANSMISSION ACQUISITION AND ANCILLARY SERVICES	181,962	0	182,962	0	185,662	0
10 POWER NON-GENERATION OPERATIONS	56,132	0	57,715	0	59,422	0
11 F&W/ENVIRONMENTAL REQUIREMENTS	171,185	0	172,276	0	173,367	0
12 GENERAL AND ADMINISTRATIVE	61,165	0	61,127	0	67,519	0
13 OTHER INCOME, EXPENSES AND ADJUSTMENTS	59,000	19,000	59,000	19,000	59,000	19,000
14 NON-FEDERAL DEBT SERVICE	601,403	79	593,923	549	598,015	125
15 DEPRECIATION AND AMORTIZATION	186,671	(34)	192,838	(36)	199,779	(38)
16 TOTAL OPERATING EXPENSES	2,443,637	20,010	2,373,515	39,107	2,481,173	63,782
17 INTEREST EXPENSE:						
18 INTEREST ON FEDERAL INVESTMENT-						
19 APPROPRIATED FUNDS	200,621	0	197,658	0	200,289	0
20 BONDS ISSUED TO U.S. TREASURY	60,059	0	77,018	0	87,641	0
21 INTEREST CREDIT ON CASH RESERVES	(27,852)	(5,857)	(32,946)	(10,464)	(37,531)	(15,072)
22 AMORTIZATION OF CAPITALIZED BOND PREMIUMS	613	0	613	0	185	0
23 CAPITALIZATION ADJUSTMENT	(45,937)	0	(45,937)	0	(45,937)	0
24 ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION	(8,000)	0	(8,000)	0	(8,000)	0
25 NET INTEREST EXPENSE	179,504	(5,857)	188,406	(10,464)	196,646	(15,073)
				0		0
26 TOTAL EXPENSES	2,623,142	14,153	2,561,921	28,643	2,677,820	48,709
27 MINIMUM REQUIRED NET REVENUES 1/	34,105	34	42,876	36	27,599	38
28 PLANNED NET REVENUES FOR RISK	97,000	97,000	97,000	97,000	97,000	97,000
29 TOTAL PLANNED NET REVENUES (27+28)	131,105	97,034	139,876	97,036	124,599	97,038
30 TOTAL REVENUE REQUIREMENT	**2,754,247**	111,187	**2,701,797**	125,679	**2,802,418**	145,747

1/ SEE NOTE ON CASH FLOW STATEMENT

Revenue Requirement – Statement of Cash Flows

This table shows the initial proposal revenue requirement statement of cash flows with columns comparing the IP with the July revenue requirement workshop. Shading identifies items that have changed since the July workshop.

	($000)	A 2007	B Change from July Workshop	C 2008	D Change from July Workshop	E 2009	F Change from July Workshop
1	CASH FROM OPERATING ACTIVITIES						
2	MINIMUM REQUIRED NET REVENUES 1/	34,105	34	42,876	36	27,599	38
3	NON-CASH ITEMS:						
4	DEPRECIATION AND AMORTIZATION	186,671	(34)	192,838	(36)	199,779	(38)
5	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	613	0	613	0	185	0
6	CAPITALIZATION ADJUSTMENT	(45,937)	0	(45,937)	0	(45,937)	0
7	ACCRUAL REVENUES	(5,179)	0	(5,179)	0	(5,179)	0
8	CASH PROVIDED BY OPERATING ACTIVITIES	170,273	0	185,211	0	176,447	0
9	CASH FROM INVESTMENT ACTIVITIES:						
10	INVESTMENT IN:						
11	UTILITY PLANT (INCLUDING AFUDC)	(209,119)	0	(280,796)	0	(142,817)	0
12	CONSERVATION	(32,000)	0	(32,000)	0	(32,000)	0
13	FISH & WILDLIFE	(36,000)	0	(36,000)	0	(36,000)	0
14	CASH USED FOR INVESTMENT ACTIVITIESS	(277,119)	0	(348,796)	0	(210,817)	0
15	CASH FROM BORROWING AND APPROPRIATIONS:						
16	INCREASE IN BONDS ISSUED TO U.S. TREASURY	201,000	0	213,000	0	205,000	0
17	REPAYMENT OF BONDS ISSUED TO U.S. TREASURY	(68,357)	0	(104,300)	0	(59,220)	0
18	INCREASE IN FEDERAL CONSTRUCTION APPROPRIATIONS	76,119	0	135,796	0	5,817	0
19	REPAYMENT OF FEDERAL CONSTRUCTION APPROPRIATIONS	(101,916)	0	(77,961)	0	(110,637)	0
20	PAYMENT OF IRRIGATION ASSISTANCE	0	0	(2,950)	0	(6,590)	0
21	CASH PROVIDED BY BORROWING AND APPROPRIATIONS	106,846	0	163,585	0	34,370	0
22	ANNUAL INCREASE (DECREASE) IN CASH	0	0	0	0	0	0
23	PLANNED NET REVENUES FOR RISK	97,000	97,000	97,000	97,000	97,000	97,000
24	TOTAL ANNUAL INCREASE (DECREASE) IN CASH	97,000	97,000	97,000	97,000	97,000	97,000

1/ Line 22 must be greater than or equal to zero, otherwise net revenues will be added so that there are no negative cash flows for the year.

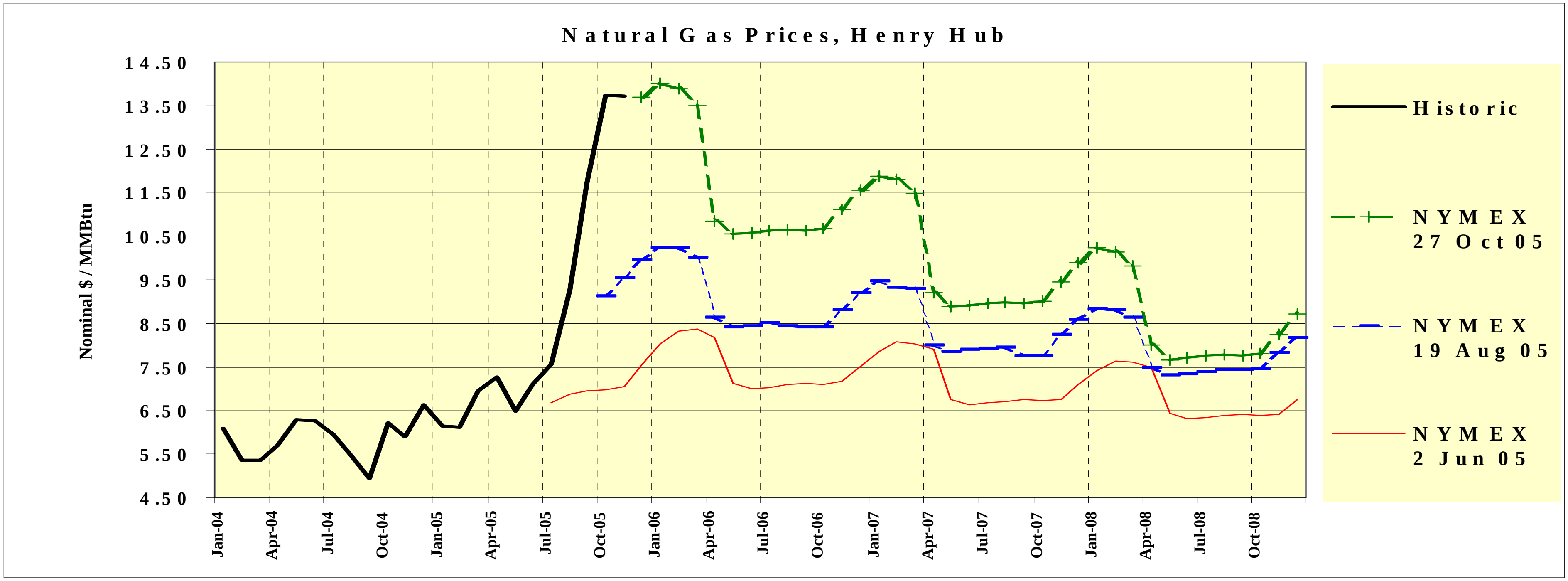
Revenue Requirement – Revised Revenue Test

This table shows the initial proposal revised revenue test with columns comparing it with the revenue requirement income statement. Shading identifies items that are different.

	($000s)	A 2007	B Change from Rev Req	C 2008	D Change from Rev Req	E 2009	F Change from Rev Req
1	REVENUES FROM PROPOSED RATES	2,837,639		2,759,352		2,706,905	
2	OPERATING EXPENSES						
3	POWER SYSTEM GENERATION RESOURCES						
4	OPERATING GENERATION RESOURCES	514,139	0	471,856	0	512,425	0
5	OPERATING GENERATION SETTLEMENT PAYMENTS	16,968	0	17,354	0	17,749	0
6	NON-OPERATING GENERATION	9,350	0	5,252	0	2,254	0
7	CONTRACTED POWER PURCHASES	150,622	(31,030)	132,854	(17,486)	144,061	(31,374)
8	RESIDENTIAL EXCHANGE/IOU SETTLEMENT BENEFITS	301,000	0	301,000	0	301,000	0
9	RENEWABLE AND CONSERVATION GENERATION	103,011	0	107,873	0	129,547	0
10	TRANSMISSION ACQUISITION AND ANCILLARY SERVICES	181,962	0	182,962	0	185,662	0
11	POWER NON-GENERATION OPERATIONS	56,132	0	57,715	0	59,422	0
12	F&W/ENVIRONMENTAL REQUIREMENTS	171,185	0	172,276	0	173,367	0
13	GENERAL AND ADMINISTRATIVE	61,165	0	61,127	0	67,519	0
14	OTHER INCOME, EXPENSES AND ADJUSTMENTS	59,000	0	59,000	0	59,000	0
15	NON-FEDERAL DEBT SERVICE	601,403	0	593,923	0	598,015	0
16	DEPRECIATION AND AMORTIZATION	186,671	0	192,838	0	199,779	0
17	TOTAL OPERATING EXPENSES	2,412,607	(31,030)	2,356,029	(17,486)	2,449,799	(31,374)
18	INTEREST EXPENSE:						
19	INTEREST ON FEDERAL INVESTMENT-						
20	APPROPRIATED FUNDS	200,621	0	197,658	0	200,289	0
21	BONDS ISSUED TO U.S. TREASURY	60,059	0	77,018	0	87,641	0
22	INTEREST CREDIT ON CASH RESERVES	(29,908)	(2,056)	(38,058)	(5,112)	(41,228)	(3,697)
23	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	613	0	613	0	185	0
24	CAPITALIZATION ADJUSTMENT	(45,937)	0	(45,937)	0	(45,937)	0
25	ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION	(8,000)	0	(8,000)	0	(8,000)	0
26	NET INTEREST EXPENSE	177,448	(2,056)	183,294	(5,112)	192,949	(3,697)
27	TOTAL EXPENSES	2,590,056	(33,086)	2,539,323	(22,598)	2,642,749	(35,071)
28	NET REVENUES	247,583		220,029		64,156	

Market Price Forecast

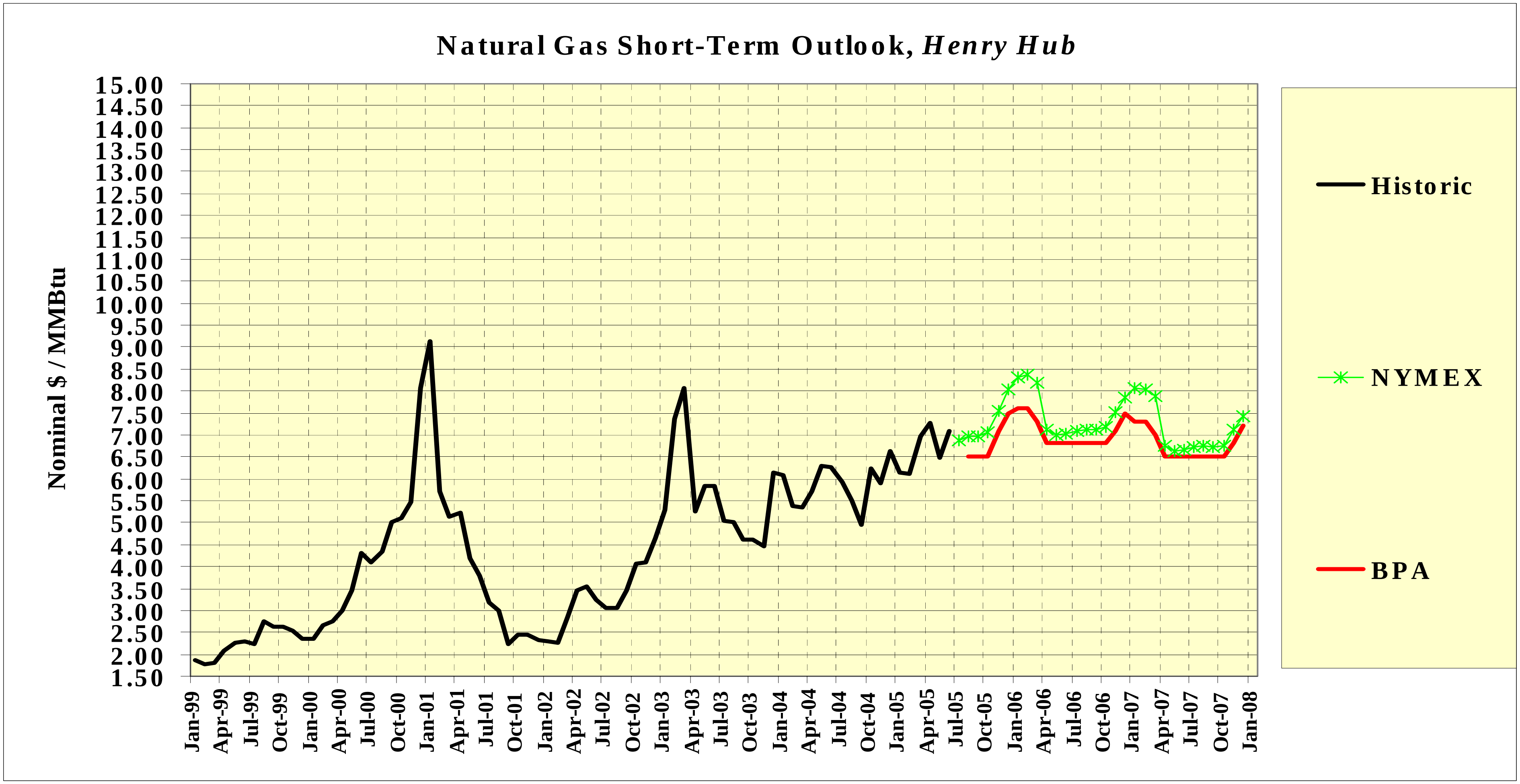
Natural Gas Prices: Futures Market Changes



	NYMEX Futures Price			19 Aug-2 Jun		27 Oct-19 Aug		27 Oct-2 Jun	
	2-Jun	19-Aug	27-Oct	Delta		Delta		Delta	
	IP	Pre-Kat	Current	Price	Pct	Price	Pct	Price	Pct
FY06	7.49	9.17	11.90	1.68	22%	2.73	30%	4.41	59%
FY07	7.26	8.49	10.20	1.23	17%	1.71	20%	2.94	40%
FY08	6.89	7.94	8.77	1.05	15%	0.83	10%	1.88	27%
FY09	6.56	7.56	7.76	0.99	15%	0.20	3%	1.20	18%
FY10	6.29	7.22	7.08	0.93	15%	-0.14	-2%	0.79	13%

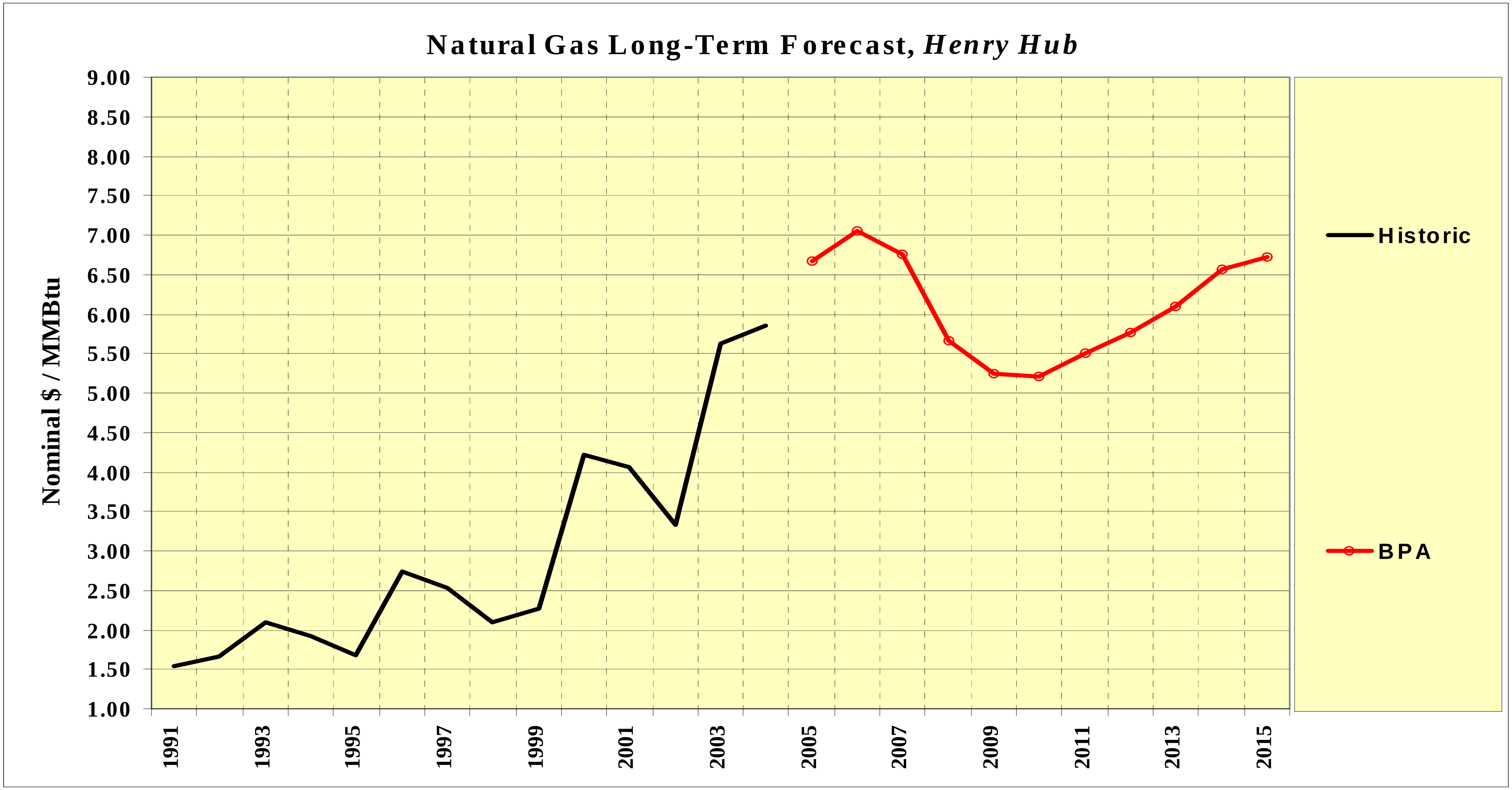
Market Price Forecast

Natural Gas Prices: Short-Term Forecast



Market Price Forecast

Natural Gas Prices: Long-Term Forecast



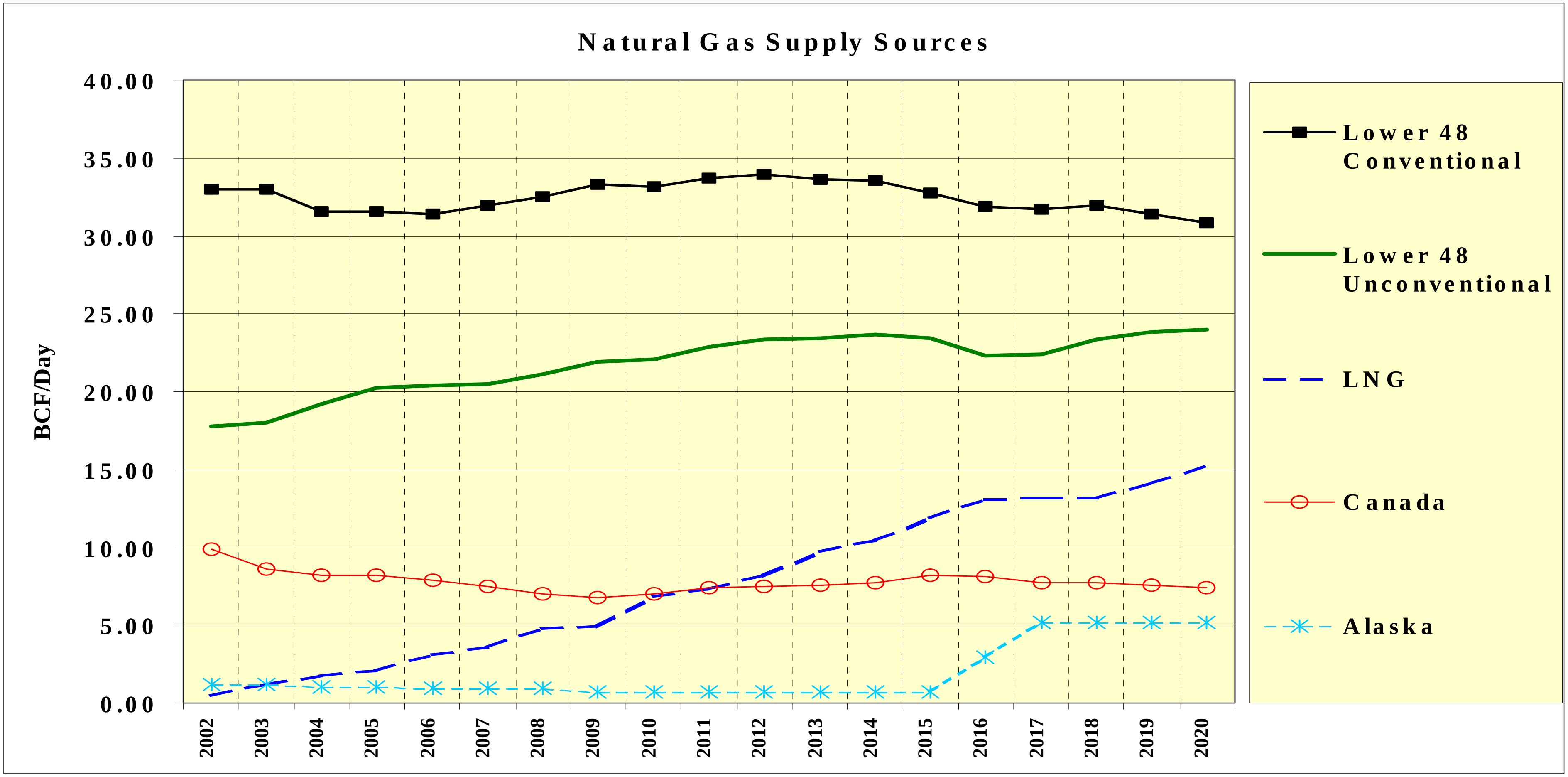
Market Price Forecast

Natural Gas Prices: Long-Term Forecast

	Nominal $/MMBtu				Basis to Henry		
	Henry	Sumas	Opal	San Juan	Sumas	Opal	San Juan
2005	6.66	5.91	5.92	5.87	0.76	0.75	0.80
2006	7.06	6.41	6.41	6.41	0.65	0.65	0.65
2007	6.76	6.16	6.16	6.16	0.60	0.60	0.60
2008	5.65	5.06	5.12	5.17	0.59	0.54	0.48
2009	5.24	4.64	4.69	4.75	0.61	0.55	0.50
2010	5.20	4.58	4.64	4.70	0.62	0.57	0.51
2011	5.51	4.87	4.93	4.99	0.64	0.58	0.52
2012	5.77	5.11	5.17	5.23	0.65	0.59	0.53
2013	6.09	5.42	5.48	5.54	0.67	0.61	0.55
2014	6.56	5.87	5.93	5.99	0.69	0.62	0.56
2015	6.72	6.02	6.08	6.14	0.70	0.64	0.58
2016	6.89	6.17	6.23	6.30	0.72	0.66	0.59
2017	7.06	6.32	6.39	6.46	0.74	0.67	0.61
2018	7.24	6.48	6.55	6.62	0.76	0.69	0.62
2019	7.42	6.64	6.71	6.78	0.78	0.71	0.64
2020	7.60	6.81	6.88	6.95	0.80	0.72	0.65

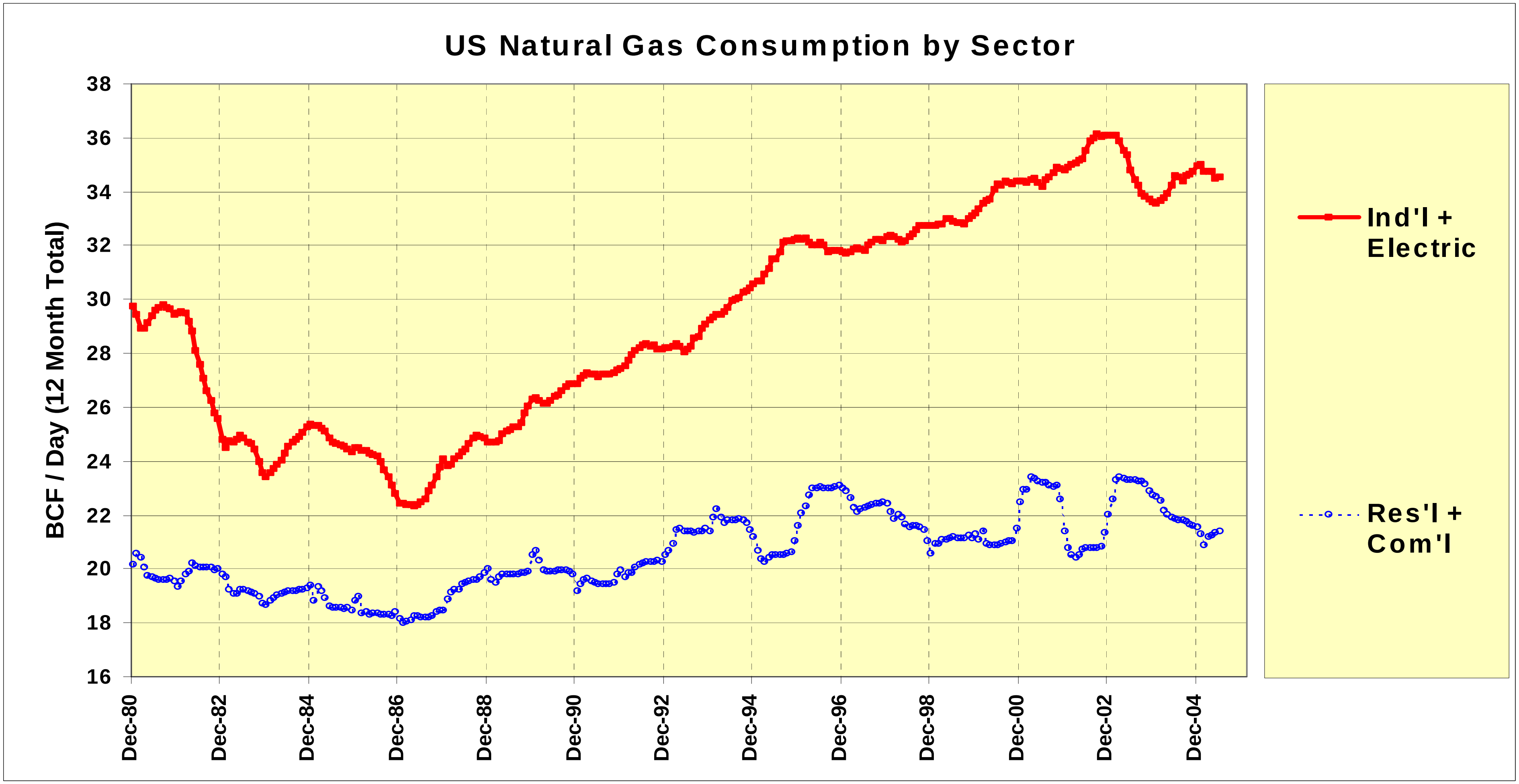
Market Price Forecast

Natural Gas Prices: EIA Supply Outlook



Market Price Forecast

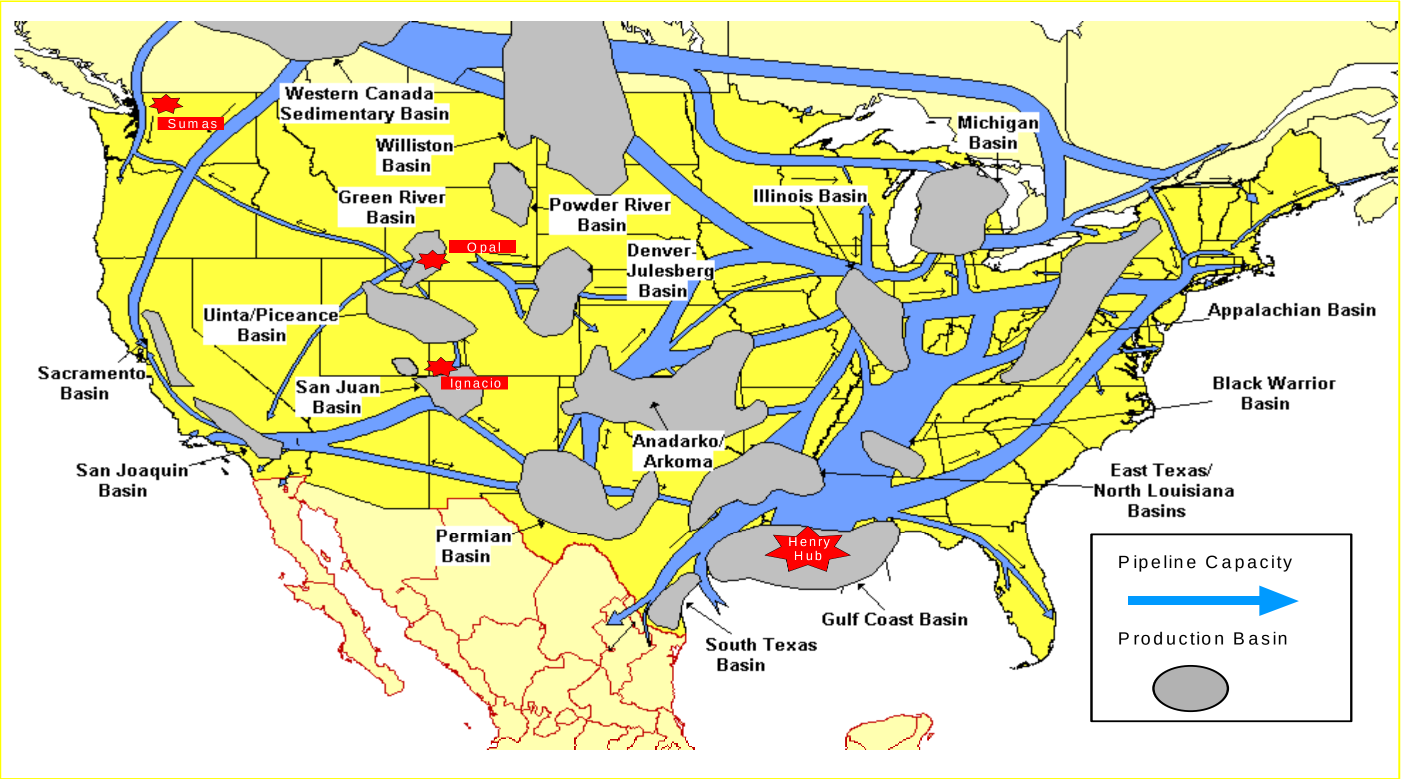
Natural Gas Prices: Historic Demand



Market Price Forecast

Natural Gas Prices: Methodology

- Henry Hub Forecast
- Western Hub Basis: Sumas, Opal, San Juan
- AURORA Areas Basis



Market Price Forecast

Natural Gas Prices: Western Hubs to AURORA Areas

Aurora Area to Western Hub Differential Price Differential (2000$/MMBtu)					
Sumas		Opal		San Juan	
PNW	0.23	UT	0.35	CO	0.36
N. Cal	0.31	WY	0.40	S. CA	0.47
		MT	0.33	AZ	0.41
		ID	0.35	NM	0.33
		N. NV	0.46	S. NV	

Market Price Forecast

Natural Gas Prices: AURORA Areas

Aurora Gas Price Forecast Input (2000$/MMBtu)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
NW Nat Gas	5.30	5.62	5.26	4.21	3.76	3.63	3.76	3.85	3.99	4.21	4.21	4.21	4.21	4.21	4.21	4.21
N.Cal Nat Gas	5.38	5.70	5.34	4.29	3.84	3.70	3.84	3.93	4.06	4.29	4.29	4.29	4.29	4.29	4.29	4.29
S.Cal Nat Gas	5.49	5.84	5.48	4.52	4.07	3.94	4.07	4.16	4.30	4.52	4.52	4.52	4.52	4.52	4.52	4.52
Can Nat Gas	5.28	5.60	5.24	4.19	3.74	3.60	3.74	3.83	3.96	4.19	4.19	4.19	4.19	4.19	4.19	4.19
Id Nat Gas	5.43	5.73	5.38	4.37	3.92	3.78	3.92	4.01	4.14	4.37	4.37	4.37	4.37	4.37	4.37	4.37
Mt Nat Gas	5.41	5.72	5.36	4.35	3.90	3.77	3.90	3.99	4.13	4.35	4.35	4.35	4.35	4.35	4.35	4.35
Wy Nat Gas	5.47	5.78	5.42	4.41	3.96	3.83	3.96	4.05	4.19	4.41	4.41	4.41	4.41	4.41	4.41	4.41
Co Nat Gas	5.39	5.74	5.39	4.42	3.97	3.84	3.97	4.06	4.20	4.42	4.42	4.42	4.42	4.42	4.42	4.42
NM Nat Gas	5.36	5.72	5.36	4.40	3.95	3.81	3.95	4.04	4.17	4.40	4.40	4.40	4.40	4.40	4.40	4.40
Az Nat Gas	5.43	5.79	5.43	4.47	4.02	3.88	4.02	4.11	4.24	4.47	4.47	4.47	4.47	4.47	4.47	4.47
Ut Nat Gas	5.43	5.73	5.38	4.37	3.92	3.78	3.92	4.01	4.14	4.37	4.37	4.37	4.37	4.37	4.37	4.37
Nv Nat Gas	5.48	5.83	5.48	4.52	4.07	3.93	4.07	4.16	4.29	4.52	4.52	4.52	4.52	4.52	4.52	4.52

Forward Flat-Block Price Forecast (FBPF)

- FBPF is described in Exhibit C to contracts and contract amendments between BPA and the regional IOUs signed May 2004 regarding benefit payments to IOUs for FYs 2007 through 2011.
- Financial benefits = (Flat-Block Price Forecast minus PF equivalent rate) * IOU allocation in MWh. Total IOU financial benefit cap is $300M, floor is $100M.
- “Big four” accounting firm KPMG, LLP, is the Qualified Third Party (QTP), requesting quarterly forward price forecasts for flat blocks of power from regional IOUs, public utilities, and marketers (Eligible Data Provider or EDP). EDPs must actively buy and sell power for resale, routinely produce forward price data, and be regularly audited by outside accounting firms.
- Governance of the process is by a committee of one representative each from BPA, a participating IOU, and a PNW public utility.

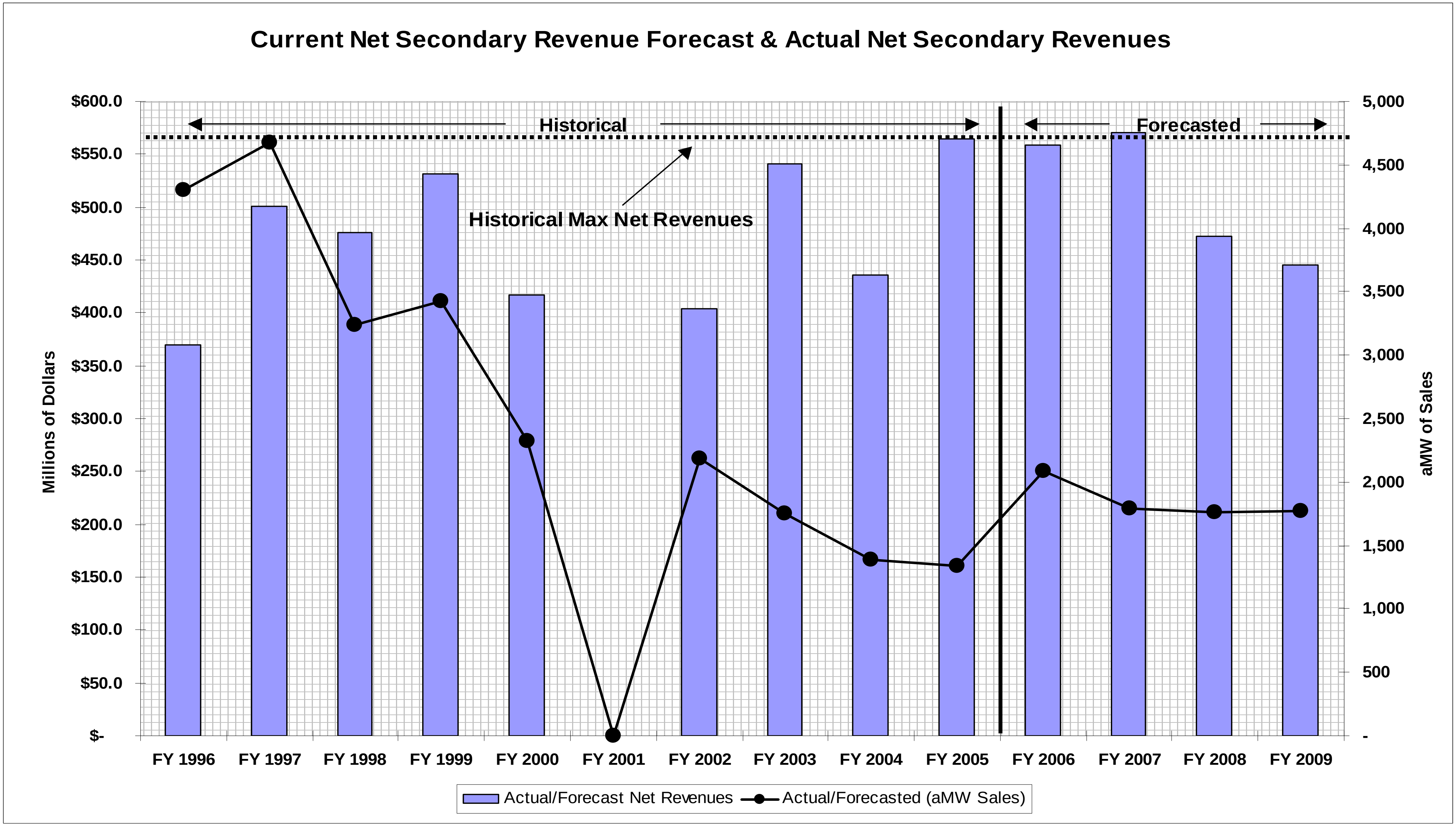
Forward Flat-Block Price Forecast (FBPF)

Process

- On dates randomly selected during January through March 2005, the QTP selected 6-8 EDPs to provide a flat-block price forecast for Q1 of FY 2007 (October-December 2006). High and low forecasts are not counted, and quarterly forecast is the simple average.
- Similar procedure was followed during April through June 2005 to determine Q2 of FY 2007. Qs 3 and 4 will be calculated during July through September and October through December, respectively. The FY 2007 forecast is the simple average of the four quarterly forecasts. The forecast will be available not later than January 15, 2006. Forecasts for FYs 2008 and 2009 will similarly be available about 9 months prior to each fiscal year start.
- Q1 2007 forecast is $48.13/MWh; Q2 forecast is $56.01/MWh. The initial WP-07 proposal forecast is the average of Q1 and Q2, $52.07/MWh. The final proposal will reflect all four quarterly forecasts.

This Agency financial information is provided for discussion purposes during this pre-rate case process.

Net Secondary Revenues



General Transfer Agreement (GTA) Delivery Charge

What is the GTA Delivery Charge? The GTA Delivery Charge is a Power Business Line (PBL) rate for deliveries of Federal power made over a third party transmission system at voltages below 34.5 kV.

Who Pays the Delivery Charge? The customer pays the GTA Delivery Charge if they receive transfer service below 34.5 kV and are not already paying TBL's Utility Delivery Charge for that particular point of delivery.

What is the proposed rate setting approach? PBL is proposing to continue to set the GTA Delivery Charge to the same rate as TBL's posted Utility Delivery rate. As adjustments are made to the Utility Delivery rate in future TBL rate cases, PBL proposes to reflect these changes in the GTA Delivery Charge for the current rate period.

General Transfer Agreement (GTA) Delivery Charge Con't

Why is PBL proposing to mirror TBL's Utility Delivery Charge? A number of customers have requested in various forums that BPA treat customers served by third-party systems in a manner comparable with customers directly connected to the FCRTS. Under this proposal, customers directly connected to the FCRTS and customers served through transfer over third-party systems would be charged the same rates for services over low voltage facilities. Setting the GTA Delivery Charge equal to TBL's Utility Delivery Charge provides customers served through transfer agreements a measure of comparability with customers that take service directly from the FCRTS.

What is the Forecasted Revenue? The revenue is forecasted to be approximately $2.3 million per year.

Generation Inputs for Ancillary & Other Services
Introduction

The purpose is to describe our proposed cost allocation method for inter-business line revenues averaged over the rate period covering fiscal years 2007-2009 and address other transmission issues that are part of PBL's rate case.

In most cases, costs are based on the embedded costs of the federal hydro system. This method identifies and allocates the portion of the federal hydro system and related costs to the provision of the ancillary and other services. Therefore, our proposal seeks to establish costs and unit costs associated with the generation inputs PBL provides to TBL for ancillary and other services.

The final costs and unit costs will establish the Annual Revenue & Expense Forecast for Ancillary & Other Services. This forecast will be used by PBL for billing TBL.

Generation Inputs for Ancillary & Other Services
Segmentation of COE/BOR Costs

What are the COE and BOR segmentation costs? The COE and BOR have a small investment in transmission facilities. COE and BOR transmission facilities perform Generation Integration (GI), Network and Delivery functions. The investment of transmission facilities must be identified and segmented so that costs can be assigned to the appropriate use.

What is the purpose of the segmentation analysis? The purpose of this analysis is to assign transmission costs to Transmission and Power purposes for the provision of these services.

What is the proposed rate setting approach? The method is the same as the last rate case and is based on TBL Segmentation definitions where Power is assigned costs for facilities that provide a GI function and Transmission is assigned costs for facilities that function as Network or Delivery facilities for TBL.

What is the Forecasted Revenue? The revenue is forecasted to be $6.8 million per year. The annual cost of the facilities assigned to Transmission are treated as a revenue credit in the generation revenue requirement and as an expense in the transmission revenue requirement.

Generation Inputs for Ancillary & Other Services
Generation Dropping

What is Generation Dropping? Generation Dropping is a controlled and coordinated action implemented by TBL that instantaneously disconnects increments of generation from the interconnected transmission system so that reliable operations can be maintained during an emergency situation. This service is provided when TBL requests PBL to instantaneously drop large increments of generation to maintain loads and voltages within acceptable levels.

What is proposed rate setting approach? The cost method is only slightly modified from the prior rate case and is based on project costs, adjusted for inflation, provided by interviews with Reclamation and COE. Costs fell into two components: First, generation drop or "forced outage utility" imparts a wear and tear component on equipment that will incrementally decrease the life and increase the maintenance of the unit. Second, the incremental impact is evaluated by computing lost revenues during the outages required during replacement or overhaul of the equipment.

What key assumptions were used in this analysis? The key assumption is that Grand Coulee Third Powerhouse hydroelectric units (each exceed 600 MW) represents PBL costs of dropping large units.

What is the Forecasted Revenue? PBL's proposed revenue forecast of costs allocated to TBL for Generation Dropping is $396,071 each year.

Generation Inputs for Ancillary & Other Services
Station Service

What is Station Service? Station Service is real power taken directly off the BPA power system for use by TBL at substations and other facilities needed for operation like Big Eddy/Celilo Complex and the Ross Complex.

What is the proposed rate setting approach? The cost method is unchanged from the prior rate case and is based on the amount of primary station service installed at each substation multiplied by an average load factor of 9.4% associated with substation service usage.

What key assumptions were used in this analysis? This cost allocation approach assumes that most of TBL's substations do not have meters for Station Service. Additionally, this method excludes purchases made by TBL from another utility for Station Service.

What is the Forecasted Revenue? PBL's proposed revenue forecast of costs allocated to TBL for Station Service is $2.29 million each year.

Generation Inputs for Ancillary & Other Services
Generation Supplied Reactive

What is Generation Supplied Reactive? Generation Supplied Reactive power is a component of electric power used by the transmission system to support and maintain voltage necessary for the reliable operation of the network. This service is necessary for TBL to operate and maintain the transmission system reliably.

What is the proposed rate setting approach? The cost method is primarily unchanged from the prior rate case and based on FERC cases referred to as the AEP methodology, which determines the embedded cost of the electric plant and then allocates a proportion of that embedded cost to Reactive through the use of a power factor.

What significant change is proposed as compared to the prior rate case? The prior rate case applied a power factor of .90. In this proposal PBL is applying a power factor of .95 for hydro generation.

What is the Forecasted Revenue? PBL's proposed revenue forecast of costs allocated to TBL for Generation Supplied Reactive is $24.9 million each year.

Generation Inputs for Ancillary & Other Services
Energy Imbalance & Generation Imbalance

What is Energy Imbalance and Generation Imbalance? Energy Imbalance is provided for the hourly difference between scheduled and actual delivered amounts of energy to a load in the BPA Control Area. Generation Imbalance is provided for the hourly difference between scheduled and actual amounts of generation delivered in the BPA Control Area.

What is the proposed rate setting approach? The cost method is unchanged from the prior rate case and is consistent with TBL's revenue forecast in the 2006-2007 Transmission Rate Case Settlement Agreement.

What key assumptions were used in this analysis? To the extent possible, PBL will provide all requested amounts of energy and generation imbalance to TBL to meet the balancing needs of the BPA Control Area.

What is the Forecasted Revenue? PBL's proposed revenue forecast of costs allocated to TBL for generation to meet imbalance needs is $0 each year.

Generation Inputs for Ancillary & Other Services
Operating Reserves

What are Operating Reserves? Operating Reserves are the unloaded generating capacity, interruptible load, or other on-demand rights that the control area is able to fully deploy within 10 minutes of a power system disturbance and that are capable of being used to serve load on a sustained basis for up to one hour. Operating Reserves include both capacity, responsive to system disturbances, and energy, made available to TBL upon notice of a system disturbance. Operating Reserves include both Spinning and Supplemental Reserves.

What is the proposed rate setting approach? The embedded cost method is unchanged from the prior rate case and is based on costs of the federal hydro system projects that provide Operating Reserve obligations to the system, including fish and wildlife program costs; generation integration and generator step up transformer costs, and planned net revenues for risk associated with the hydro system. The generation costs assigned to Reactive is subtracted to avoid double counting.

What costs were excluded from the embedded cost analysis? Costs of the Columbia Generating Station, non-performing assets, conservation, and the residential exchange program are excluded.

Generation Inputs for Ancillary & Other Services
Operating Reserves Con't

What is the Per Unit Generation Input Cost? The generation input cost is proposed to be $6.96 kW-mo. This up-to cost allows the business lines to adjust the cost that is charged to the TBL through the inter-business line bill.

How is the Per Unit Generation Input Cost Determined? The per unit cost of $6.96 kW-mo is calculated by dividing the adjusted annual FCRPS hydro revenue requirement of ~$35 million by the PBL Operating Reserve Obligation of 420 MW (net of self-supply and third-party supply to TBL), times 12 months, times 1,000.

What is the Forecasted Revenue? PBL's proposed revenue forecast of costs allocated to TBL for Operating Reserves is $35 million[1] each year.

1/ 420 hourly average MW of PBL Operating Reserve Obligation, times 6.96 kW-mo, times 12 months, times 1000.

Generation Inputs for Ancillary & Other Services
Regulating Reserves

What are Regulating Reserves? Regulating Reserves are generating capacity of a power system that is immediately responsive to Automatic Generation Control (AGC) signals without human intervention and is sufficient to provide normal regulating margin.

What is the proposed rate setting approach? The embedded cost method is unchanged from the prior rate case and is based on costs of the Big 10 federal hydro system projects that provide Regulating Reserve obligations to the system including fish and wildlife program costs; generation integration and generator step up transformer costs, and planned net revenues for risk associated with the hydro system. The generation cost assigned to Reactive is subtracted to avoid double counting. This approach is similar to Operating Reserves.

What costs were excluded from the embedded cost analysis? Costs of the Columbia Generating Station, non-performing assets, conservation, and the residential exchange program are excluded.

Generation Inputs for Ancillary & Other Services
Regulating Reserves Con't

What are the components of the generation input cost? The generation input costs contains two components: First, a base charge based on embedded costs of the Big 10 hydro units. Second, an AGC Adder cost to account for loss of efficiency and incremental increased O&M cost due to the fact that the generating unit is required to operate more dynamically than a base-loaded unit.

What is the Per Unit Generation Input Cost? The generation input cost is proposed to be $8.29 kw-mo. This is comprised of $6.74 kw-mo base cost plus $1.55 kw-mo AGC Adder. This up-to cost allows the business lines to adjust the cost that is charged to the TBL through the inter-business line bill.

How is the Per Unit Generation Input Cost Determined? The per unit cost of $8.29 kW-mo is calculated by dividing the adjusted annual FCRPS hydro revenue requirement of ~$15 million by the TBL Regulating Reserve Obligation of 150 MW (excludes capacity to meet 200 MW of Load Following needs of PBL's Requirements Customers), times 12 months, times 1,000.

What is the Forecasted Revenue? PBL's proposed revenue forecast of costs allocated to TBL for Regulating Reserves is $15 million[1] each year.

1/ 150 hourly average MW of TBL's Share of Regulating Reserve, times 8.29 kW-mo, times 12 months, times 1000

Generation Inputs for Ancillary & Other Services

Operating Reserves Credit

What is the proposed Operating Reserve Credit? PBL is proposing to modify the form of the credit that is based on the PBL revenue received from TBL related to the provision of generation inputs for Operating Reserves.

Why is PBL proposing the Operating Reserve Credit? There are two reasons for this modification. First, PBL intends to solve a revenue under recovery problem that has arisen within the current WP-02 rate period concerning the application of the Operating Reserves revenue credit. Second, by solving the under recovery issue BPA intends to correct a rate inequity that has developed among firm power requirements customers.

How does this under recovery affect BPA's firm power requirements currently? PF firm power requirements customers that elect to self-supply and third-party supply receive (1) the WP-02 Operating Reserves revenue credit in their base PF rate and (2) the benefit of not paying the TBL tariff rate for Operating Reserves. This creates inequity among BPA's firm power requirements customers. Currently, the forecasted OR revenue is spread as a rate benefit to all firm power requirements customers, regular PF customers receive a lower base rate, and Slice customers receive the slice percentage of the costs/credits.

Generation Inputs for Ancillary & Other Services
Operating Reserves Credit Con't

What is the proposed rate setting approach? PBL is proposing to forecast $0 revenue and will provide an Operating Reserve Credit (ORC) to requirements power customers that purchase Operating Reserves from TBL. This proposal better reflects actual revenues PBL receives from generation inputs provided to TBL and ensures cost recovery consistent with the power revenue requirement and eliminates the inequity among firm power customers that exists currently.

What key assumptions were used in prior rate case? The last rate proceeding PBL assumed that federal generation would meet the entire Operating Reserve obligation of the BPA Control Area since the ability for transmission customers to self-supply or get third party supply of Operating Reserves did not exist at the time. Therefore, PBL credited the expected revenues from providing generation inputs for TBL Operating Reserves against PBL's total revenue prior to computing all PF rates.

How is the proposed ORC determined and what is the credit amount? The ORC is determined from the total PBL revenue forecasted for generation inputs to be recovered from TBL divided by the total forecasted PF loads associated with customers obtaining OR from TBL that are supported with those generation inputs. The ORC is proposed to be 0.89 mills/kWh.

Generation Inputs for Ancillary & Other Services

Summary of PBL's Proposed FY07-09 Revenue Forecast

		Gross Revenue			
		Average over Rate Period	FY07	FY08	FY09
	ANCILLARY & OTHER SERVICES				
1	Segmentation of COE/BOR Costs	$6,879,333	$6,321,000	$6,801,000	$7,516,000
2	Federal RAS for Generation Dropping	$312,895	$312,896	$312,895	$312,895
3	Station Service	$2,292,620	$2,292,620	$2,292,620	$2,292,620
4	Generation Supplied Reactive	$24,933,000	$24,933,000	$24,933,000	$24,933,000
5	Energy/Generation Imbalance	$0	$0	$0	$0
6	Operating Reserve - Spin & Supp	$35,078,400	$35,078,400	$35,078,400	$35,078,400
7	Regulating Reserve	$14,922,000	$14,922,000	$14,922,000	$14,922,000
8	**TOTAL ANCILLARY & OTHER SERVICES**	**$84,418,248**	**$83,859,916**	**$84,339,915**	**$85,054,915**

Summary of Proposed Rates

Average “Posted” Rates

Average PF Rate (without CRACs and DDC):

$31.11 / MWh

- $ 0.89 / MWh (Operating Reserve Credit)

$30.22

Slice Rate:

$1,892,726 per 1 percent of Slice

Average PF Exchange Rate:

$66.7 /MWh

Average NR Rate:

$63.3 /MWh

Average IP Rate:

$49.9 /MWh

Risk Mitigation Package for FY 2007-2009

Overview

– **Starting FY 2007 PBL Reserves**
  - Based on FY 2005 3rd Quarter Review and forecast of FY 2006 financials

– **Agency reserves not attributable to generation**
  - Agency reserves not attributable to generation will be temporarily available for power rate making purposes for FY 2007 as long as they do not reduce TBL's ability to satisfy the 95% TPP standard for FY 2006 – 2007.

– **Cost Recovery Adjustment Clause (CRAC)**
  - Annual Cap = $300M
  - Triggers on AMNR (starting FY 2000) equivalent to approximately $500M in PBL reserves

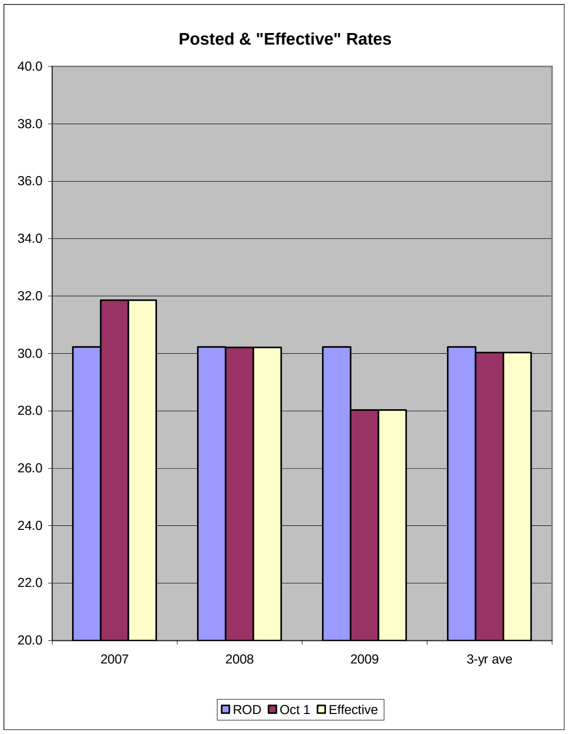
– **National Marine Fishery Service, Federal Columbia River Power System, Biological Opinion Rate Adjustment Mechanism (NFB Adjustment)**
  - Modifies Annual CRAC Cap

– **Planned Net Revenues for Risk**
  - $97M has been added to the Revenue Requirement to achieve the 92.6% three-year TPP standard

– **Dividend Distribution Clause (DDC)**
  - Triggers on AMNR equivalent of $800M in PBL reserves

Initial Proposal Risk Mitigation Summary

RC#5, 100% credit of Sec Rev, $300M CRAC, 06 Cap=706, Flat PNRR, $50M LiqRes | PBL reserves



Notes **3-year TPP: 92.6%**

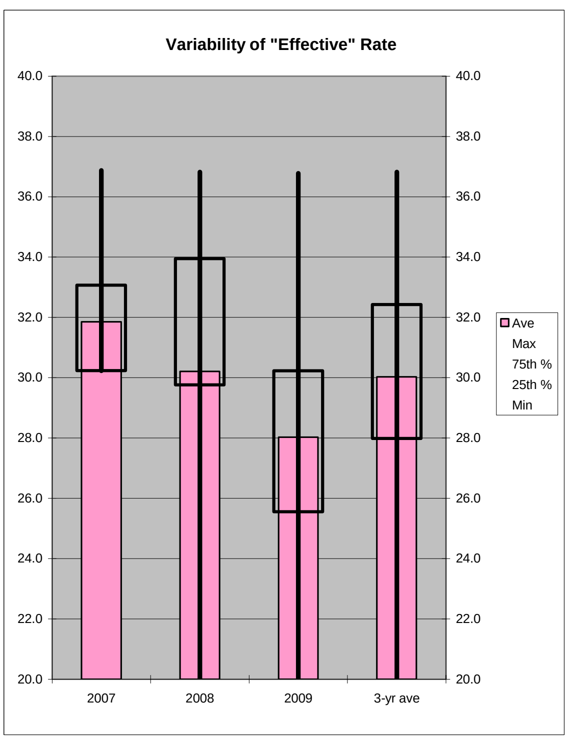
Not yet real Init. Prop. data, but closer
2007-9 data is Init. Prop. with a few issues outstanding
2005-6 data from 3rd Q Review with two $8M tweaks

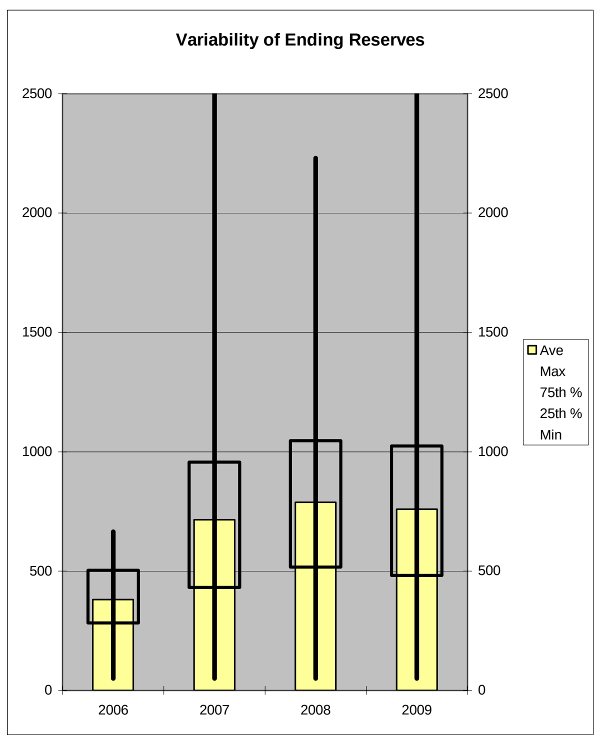
Rates are approximations of an average PF rate.
"ROD" rate is what is published in the Rod.
"Oct 1" rate is the rate going into effect on Oct 1 - this will take into account any CRAC or DDC on top of Rod rate.
"Effective" rate is a calculation that takes into account the rate calculated in the ROD, plus any CRAC or DDC amounts that into effect on Oct 1, plus any after-the-fact adjustments from a Rebate.

The hollow box on the variability charts below shows the 75th and 25th percentile values - 50% of the outcomes fall between these two values. The vertical line shows the maximum and minimum values over all 3000 games.

The DDC is calculated near the end of a year but isn't distributed till the next year, so it doesn't cap ending reserves immediately.

in millions	2007	2008	2009	
DDC threshold	$ 800	$ 800	$ 800	
DDC caps	$ 5,000	$ 5,000	$ 5,000	
CRAC threshold	$ 470	$ 500	$ 500	
CRAC caps	$ 300	$ 300	$ 300	
CRAC trigger freq.	39%	45%	23%	
CRAC at max freq.	14%	18%	8%	
PNRR	**2007**	**2008**	**2009**	3-yr ave.
	$ 97	$ 97	$ 97	$ 97





2007 GENERAL RATE SCHEDULE PROVISIONS

Section D: GRSPs

D. Cost Recovery Adjustment Clause

The CRAC is an upward adjustment to the FY 2007-2009 energy base rates given in the Record of Decision (ROD). It is calculated by a formula that compares PBL Accumulated Modified Net Revenues (AMNR) (as defined by the CRAC) to three annual Thresholds, and places caps on the amount of revenue that can be generated each year.

The CRAC applies to Light Load Hours (LLH) and Heavy Load Hours (HLH) energy sales under these firm power rate schedules:
- PF-07 [Preference (excluding the PF Slice Product) and PF Exchange Power];
- Industrial Firm Power (IP-07);
- New Resource Firm Power (NR-07);
- BPA's contractual obligations for Irrigation Rate Mitigation Product sales.

The CRAC also applies to the calculations of:
- the 2200 aMW of Monetary Benefits provided under the Investor Owned Utility Residential Exchange Program Settlement benefits (IOU REP Settlement benefits); and
- the benefits provided to Direct Service Industry (DSI) customers under the FY 2005 DSI Service ROD.

The CRAC does not apply to:
- sales under the PF Slice Product; or
- power sales under Pre-Subscription contracts to the extent prohibited by such contracts.

1. Calculations for the Cost Recovery Adjustment Clause

Prior to the beginning of each fiscal year of the rate period (*i.e.*, FY 2007-2009), BPA will forecast the current year's end-of-year AMNR. If the forecasted AMNR is less than the defined CRAC Threshold for that fiscal year, the CRAC will trigger, and a rate increase will go into effect beginning in October of the upcoming fiscal year.

a. Calculating the CRAC Amount

CRAC Amount is the lower of:

CRAC Threshold minus forecasted AMNR;

or

The Maximum CRAC Recovery Amount (Cap) for each year, shown in Table B below.

Table B: CRAC Annual Thresholds and Caps
[Dollars in Millions]

AMNR Calculated at end of Fiscal Year	CRAC Applied to Fiscal Year	CRAC Threshold*	Approx. Threshold as Measured in PBL Reserves	Maximum CRAC Recovery Amount (Cap)**
2006	2007	-$193	$470	$300
2007	2008	-$36	$500	$300
2008	2009	-$45	$500	$300

* As measured by AMNR.
** The Maximum CRAC Recovery Amount (Cap) may be modified to account for adjustments made to the Cap by the NFB Adjustment (if triggered) calculated at the end of FYs 2006, 2007, and 2008.

Where CRAC Amount is the additional net revenue that an increase in rates, due to the CRAC, is intended to generate in the next fiscal year.

Where CRAC Threshold is the "trigger point" for invoking a rate increase under the CRAC. The CRAC Threshold is specified for the end of FYs 2006, 2007, and 2008, in Table B.

Where AMNR is generation function net revenues, as accumulated since 1999, at the end of each year for FY 2006 through FY 2008. The forecast of AMNR is used to determine if the CRAC Threshold has been reached, and if so, the required CRAC Amount to be collected. The forecast of AMNR through the end of each fiscal year will be calculated by determining the accumulated annual Modified Net Revenue (MNR) during the rate period.

Where the MNR for any given fiscal year is defined as generation function accrued revenues less accrued expenses (in accordance with Generally Accepted Accounting Principles) with three exceptions:

(1) The calculation of MNR will exclude the impact of adopting Financial Accounting Standard 133, Accounting for Derivative Instruments and Hedging Activities (including supplemental standards issued by FASB regarding derivatives and hedging activities), and actual Energy Northwest (EN) debt service. (BPA has adopted FASB Statement No. 133, *Accounting for Derivative Instruments and Hedging Activities as amended by FASB Statements 137, 138, and 149 and interpreted by Derivatives Implementation Group issues (together, "FAS 133")* as of October 1, 2000.)

(2) The calculation of MNR will include forecasted EN debt service identified in the WP-07 Final Studies.

(3) The forecast of MNR will be based on actual generation function revenues and expenses for the first three quarters of the year and forecasted results for the remainder of the year, and will include revenues and expenses that are associated with the production, acquisition, marketing, and conservation of electric power. The transmission function accrued revenues and expenses are excluded. The MNR includes impacts on forecasted revenues, positive or negative, from contractual true-up pursuant to the Slice Agreement.

<u>Where Maximum CRAC Recovery Amount (Cap)</u> is the maximum annual amount that is allowed to be recovered through the CRAC.

b. Converting the CRAC Amount to a Percentage

Once the CRAC Amount is determined, that amount will be converted to the CRAC Percentage. The additional CRAC revenue will be generated by applying this percentage to the applicable power rates and benefits in the following way:

(1) The CRAC Amount is the percentage increase applied to customers' LLH and HLH base energy sales to each product subject to the CRAC adjustment.

(2) The CRAC Amount will be applied to the energy rate components of the lowest cost-based power rate schedule (the PF Block Product as defined by the IOU REP Settlement) used to calculate the annual IOU REP Settlement benefits. This may change the IOU REP Settlement benefits, depending on the effects of the cap and floor. This change, if any, will be factored into the calculation of the CRAC Percentage.

(3) The CRAC Amount will be applied to the energy rate components of the PF Block Rate used to calculate the annual DSI service benefits. The calculation of the CRAC percentage will not include any anticipated effect on the DSI service benefits.

c. Accounting for IOU Impact on the CRAC Percentage

The IOU REP Settlement benefits are constrained by a cap and floor. The CRAC Amount that will be collected by reducing the IOU REP Settlement benefits is calculated first before calculating the portion of the CRAC Amount that needs to be collected from the PF products subject to the CRAC. First, it is assumed that the CRAC Amount can be recovered from both the IOU REP Settlement benefits and the CRAC-adjusted PF rates. A check is then performed to see whether the cap and floor constrains the portion of the CRAC Amount that can be collected via reductions in the IOU REP Settlement benefits. The PF portion of the CRAC Amount is the CRAC Amount less the portion of the CRAC Amount that can be collected from the IOU REP Settlement benefits. The CRAC Percentage is calculated by dividing the PF

CRAC Amount by the most current forecast of LLH and HLH revenues from products subject to the CRAC. Specifically:

(1) InitialUnconstrainedBenefits = (Forward_Flat-Block_Price – PF_Block_Product) * 2200aMW * HoursInYear

Where Forward_Flat-Block_Price for FY 2007 is the price assumed in the WP-07 Final ROD, and will be calculated for FY 2008 and FY 2009.

(2) If InitialUnconstrainedBenefits > 300 then InitialConstrainedBenefits = 300;
If InitialUnconstrainedBenefits < 100 then InitialConstrainedBenefits = 100;
Otherwise, InitialConstrainedBenefits = InitialUnconstrainedBenefits.

(3) InitialIOU_CRAC_Amount = CRAC_Amount * 2200 / (CRAC_RevenueBasis + .774 * 2200 * HoursInYear)

Where CRAC_RevenueBasis is the total LLH and HLH generation function revenue for products that are subject to the CRAC, based on the then most current revenue forecast for the relevant BPA fiscal year.

Where .774 is the percentage of IOU REP Settlement benefits attributable to non-Slice loads.

Where HoursInYear is the number of hours in the fiscal year, adjusting for leap year in FY 2008.

(4) PreliminaryUnconstrainedBenefits = InitialUnconstrainedBenefits – InitialIOU_CRAC_Amount

(5) If PreliminaryUnconstrainedBenefits > 300 then PrelminaryConstrainedBenefits = 300;
If PreliminaryUnconstrainedBenefits < 100 then PreliminaryConstrainedBenefits = 100;
Otherwise, PreliminaryConstrainedBenefits = PreliminaryUnconstrainedBenefits.

(6) FinalIOU_CRAC_Amount = InitialConstrainedBenefits – PreliminaryConstrainedBenefits

Where FinalIOU_CRAC_Amount is the amount by which the total IOU REP Settlement benefits for this year are to be reduced from the amount calculated from the Forward Flat-Block Price (the market price in the WP-07 Final ROD for FY 2007, or the market price from brokers for FY 2008 and FY 2009), and the PF rate without the CRAC from the WP-07 Final ROD.

(7) PF_CRAC_Amount = CRAC Amount – FinalIOU_CRAC_Amount

(8) CRAC Percentage = PF_CRAC_Amount / CRAC Revenue Basis

For products subject to the CRAC, the CRAC percentage will be applied to HLH and LLH base energy rates for the twelve months beginning in October and ending the following September. The IOU Settlement REP benefits and the DSI service benefits calculation will be adjusted if the benefits fall below the cap or rise above the floor..

2. CRAC Adjustment Timing

Prior to the beginning of each fiscal year of the rate period, BPA will determine whether the forecast of the current fiscal year AMNR is below the CRAC Threshold. If the AMNR is forecasted to fall below the CRAC Threshold, BPA will assess an adjustment to applicable rates for power deliveries beginning in October.

Customers will be notified, on or about September 15, of the percentage increase applicable to the base, if any, due to the CRAC.

a. CRAC Notification Process

BPA shall use the following notification procedures:

(1) **Financial Performance Status Reports**

Each quarter, BPA shall post to its external website (www.bpa.gov), preliminary, unaudited, *year-to-date* aggregate financial results for the generation function, including AMNR.

For the 2nd and 3rd Quarter Review, BPA shall post to its external website (www.bpa.gov), the preliminary, unaudited *end-of-year* forecast of AMNR attributable to the generation function.

(2) **Notice of CRAC Trigger**

BPA shall complete a forecast of current fiscal end-of-year AMNR prior to the beginning of the next fiscal year. BPA shall notify all customers and rate case parties around mid-September, in each FYs 2006-2008 (prior to the beginning of the next fiscal year), if the expected value of AMNR is forecasted to fall below the CRAC Threshold for the subsequent fiscal year and, if so, the extent to which BPA intends to adjust rates due to the CRAC. Notification will be posted on BPA's website and will include the AMNR based on audited results, for the prior fiscal year, the forecast of end-of-year AMNR, the calculation of the Revenue Amount, and the forecast of the CRAC Percentage. The notice shall also describe the data and assumptions relied upon by BPA for the AMNR determination. Such data, assumptions, and documentation, if non-proprietary and/or non-privileged, shall be made available for review from BPA upon request.

Prior to the end of each fiscal year, for any year in which the AMNR is forecasted to fall below the CRAC Threshold, BPA staff shall conduct a public forum to explain the AMNR forecast, the calculation of the CRAC Amount and the CRAC Percentage, and to demonstrate that the CRAC has been implemented in accordance with these GRSPs. The forum will provide an opportunity for public comment.

On or about September 30 of any fiscal year in which the AMNR is forecasted to fall below the CRAC Threshold, BPA will post to the BPA website the final calculation of the percentage adjustment to each product and the dollar adjustment to each benefit subject to the CRAC as described above. This will include any National Marine Fisheries Service [NMFS] Federal Columbia River Power System [FCRPS] Biological Opinion [BiOp] **(**NFB) adjustment to the CRAC calculation.

3. The NFB Adjustment (National Marine Fisheries Service [NMFS] Federal Columbia River Power System [FCRPS] Biological Opinion [BiOp] Adjustment)

The NFB adjustment results in an upward adjustment to the CRAC Maximum Recovery Amount (Cap) for any year in the rate period if financial impacts on fish and wildlife costs arise from a specified set of circumstances. The NFB Adjustment calculation will result in an increase in the annual CRAC maximum recovery amount defined in Table B for the next fiscal year following the year the NFB Adjustment was triggered. The NFB Adjustment is applicable to each fiscal year (FY 2007 through FY 2009).

a. Triggering the NFB Adjustment

The NFB Adjustment will address changes in financial results due to the anadromous fish portion of Fish and Wildlife cost categories only when those impacts result from changes in FCRPS Endangered Species Act (ESA) compliance as required by a court order (including court-approved agreements), an agreement related to litigation, a new NMFS FCRPS BiOp, or Recovery Plans under the ESA. Financial impacts include foregone revenue, power purchases, direct program expense, fish and widlife credits, Corps of Engineers and Bureau of Reclamation Operations and Maintenance, and capital repayment. Financial impacts will be calculated net of estimated 4(h)(10)(C) credits.

b. Formula for Calculating the NFB Adjustment

The calculation will compare the financial results of the modeled operation of the power system under the total set of fish and wildlife mitigation measures actually employed, to the financial results of the modeled operation of the power system under the same set of fish and wildlife mitigation measures except with the removal of the court-ordered changes (or court-approved, etc.).

The NFB Adjustment calculation will be determined by the following formula:

NFB Adjustment =

Expected Net Revenue Before Financial Impacts

Minus

Expected Net Revenue After Financial Impacts

Where the NFB Adjustment is the difference in generation function modified net revenues before and after the change in the modeled operations of the power system.

Where the Expected Net Revenue Before Financial Impacts is the modeled operation of the power system under the total set of fish and wildlife mitigation measures actually employed for the current fiscal year, net of estimated 4(h)(10)(C) credits.

Where the Expected Net Revenue After Financial Impacts is the modeled operation of the power system under the same set of fish and wildlife mitigation measures except with the removal of the court-ordered changes for the current fiscal year, net of estimated 4(h)(10)(C) credits.

The adjustment to the CRAC Cap will be determined by the following formula:

Modified CRAC Maximum Recovery Amount =

Maximum CRAC Recovery Amount

Plus

NFB Adjustment

Where the Modified Maximum CRAC Recovery Amount (Cap) is the increase in the Maximum CRAC Recovery Amount by the amount calculated by the NFB Adjustment.

Where the Maximum CRAC Recovery Amount (Cap) is the maximum annual amount planned to be recovered at the beginning of the FY 2007-2009 rate period (see Table B).

c. NFB Adjustment Timing

Prior to the beginning of each fiscal year of the rate period, BPA will determine the financial impacts, if any, of the Fish and Wildlife program resulting from a court order, an agreement related to litigation, a new NMFS FCRPS BiOp and/or Recovery

Plans under the ESA. BPA will propose around mid-September the increase to the CRAC maximum recovery amount for the next fiscal year.

d. NFB Notification Process

BPA will notify customers within thirty days of the occurrence of an NFB adjustment trigger event, as defined above. This initial notification, posted to BPA's website, will include a description of the event. However, the financial impact of the event will not be calculated until the forecast of the end-of-year AMNR calculation is performed prior to the beginning of the next fiscal year. There can be more than one NFB adjustment trigger event in any year. There will only be one calculation of the NFB adjustment amount in any year.

No later than September 30, BPA will notify customers of the calculated final CRAC percentage. Any NFB adjustment will be included in this final notification.

Section F: GRSPs

F. Dividend Distribution Clause

The DDC is a rate adjustment establishing criteria for the distribution of funds to customers. The DDC enables BPA to distribute funds to eligible firm power customers and establishes the mechanism to be used to make a distribution. The amount of the distribution is calculated by a formula that compares PBL Accumulated Modified Net Revenues (AMNR) (as defined by the DDC) to three annual Thresholds. See Table C.

The DDC applies to Light Load Hours (LLH) and Heavy Load Hours (HLH) energy sales under these firm power rate schedules:

- PF-07 [Preference (excluding the PF Slice Product) and PF Exchange Power];
- Industrial Firm Power (IP-07);
- New Resource Firm Power (NR-07);
- BPA's contractual obligations for Irrigation Rate Mitigation Product sales.

The DDC also applies to the calculations of:

- the 2200 aMW of Monetary Benefits provided under the Investor-Owned Utility Residential Exchange Program Settlement benefits (IOU REP Settlement benefits); and
- the benefits provided to Direct Service Industry (DSI) customers under the FY 2005 DSI Service ROD.

The DDC does not apply to:

- sales under the PF Slice Product; or
- power sales under Pre-Subscription contracts to the extent prohibited by such contracts.

1. Calculations for the Dividend Distribution Clause

Prior to the beginning of each fiscal year of the rate period (*i.e.*, FY 2007-2009), BPA will forecast the current year's end-of-year AMNR. If the forecasted AMNR is greater than the defined DDC Threshold for that fiscal year, the DDC will trigger, and a rate reduction will go into effect beginning in October of the upcoming fiscal year.

a. Calculating the DDC Amount

DDC Amount =

Forecasted AMNR

minus

DDC Threshold, shown in Table C below.

Table C: DDC Thresholds
[Dollars in Millions]

AMNR Calculated at End of Fiscal Year	DDC Applied to Fiscal Year	DDC Threshold*	Approx. Threshold as Measured in PBL Reserves
2006	2007	$137	$800
2007	2008	$264	$800
2008	2009	$255	$800

* As measured by AMNR.

<u>Where DDC Amount</u> is the reduction in modified net revenues that a decrease in rates, due to the DDC, is intended to generate in the next fiscal year.

<u>Where DDC Threshold</u> is the "trigger point" for invoking a rate decrease under the DDC. The DDC Threshold is specified for the end of FYs 2006, 2007, and 2008, in Table C.

<u>Where AMNR</u> is generation function net revenues, as accumulated since FY 1999, and at the end of each year for FY 2006 through FY 2008. The forecast of AMNR is used to determine if the DDC Threshold has been reached, and the required Distribution Amount to be distributed. The forecast of AMNR through the end of each fiscal year will be calculated by determining the accumulated annual Modified Net Revenue (MNR) during the rate period.

<u>Where the MNR</u> for any given fiscal year is defined as generation function accrued revenues less accrued expenses, (in accordance with Generally Accepted Accounting Principles), with three exceptions:

(1) The calculation of MNR will exclude the impact of adopting Financial Accounting Standard 133, Accounting for Derivative Instruments and Hedging Activities, and actual Energy Northwest debt service. (BPA has adopted FASB Statement No. 133, *Accounting for Derivative Instruments and Hedging Activities as amended by FASB Statements 137, 138, and 149 and interpreted by Derivatives Implementation Group issues (together, "FAS 133")* as of October 1, 2000.)

(2) The calculation of MNR will include forecasted EN debt service identified in the WP-07 Final Studies.

(3) The forecast of MNR will be based on actual generation function revenues and expenses for the first three quarters of the year and forecasted results for the remainder of the year, and will include revenues and expenses that are associated with the production, acquisition, marketing, and conservation of electric power. The transmission function accrued revenues and expenses are

excluded. The MNR includes impacts on forecasted revenues, positive or negative, from contractual true-up pursuant to the Slice Agreement.

b. Converting the DDC Amount to a Percentage

Once the DDC Amount is determined, that amount will be converted to the DDC Percentage. The DDC Percentage applies as follows:

(1) The DDC Amount is the percentage decrease applied to customers' LLH and HLH base energy sales to each product subject to the DDC adjustment.

(2) The DDC Amount will be applied to the energy rate components of the lowest cost-based rate schedule (the PF Block Product as defined by the IOU REP Settlement) used to calculate the annual IOU REP Settlement benefits. This may change the IOU REP Settlement benefits, depending on the effects of the cap and floor. This change, if any, will be factored into the calculation of the DDC Percentage.

(3) The DDC Amount will be applied to the energy rate components of the PF Block Rate used to calculate the annual DSI service benefits up to the cap set in the DSI Service ROD. The calculation of the DDC percentage will not include any anticipated effect on the DSI service benefits.

c. Accounting for IOU Impact on the DDC Percentage

The IOU REP Settlement benefits are constrained by a cap and floor. The DDC Amount that will be distributed by reducing the IOU REP Settlement benefits is calculated first before calculating the portion of the DDC Amount distributed to the PF products eligible for the DDC. First, it is assumed that the DDC Amount can be distributed to both the IOU REP Settlement benefits and the DDC-adjusted PF rates. A check is then performed to see whether the caps and floors constrain the portion of the DDC Amount that can be distributed via increases in the IOU REP Settlement benefits. The PF portion of the DDC Amount is the DDC Amount less the portion of the DDC Amount that can be distributed from the IOU REP Settlement benefits. The DDC Percentage is calculated by dividing the PF DDC Amount by the most current forecast of LLH and HLH revenues from products subject to the DDC. Specifically:

(1) InitialUnconstrainedBenefits = (Forward_Flat-Block_Price – PF_Block_Product) * 2200aMW * HoursInYear

Where HoursInYear is the number of hours in the fiscal year, adjusting for leap year in FY 2008.

(2) If InitialUnconstrainedBenefits > 300 then InitialConstrainedBenefits = 300;
If InitialUnconstrainedBenefits < 100 then InitialConstrainedBenefits = 100;
Otherwise, InitialConstrainedBenefits = InitialUnconstrainedBenefits.

Where Forward_Flat-Block_Price for FY 2007 is the price assumed in the WP-07 Final ROD, and will be calculated for FY 2008 and FY 2009.

(3) InitialIOU_DDC_Amount = DDC_Amount * 2200 / (DDC_RevenueBasis + .774 * 2200 * HoursInYear)

Where the DDC Revenue Basis is the total LLH and HLH generation function revenue for products that are subject to the DDC, based on the then most current revenue forecast for the relevant BPA fiscal year.

Where .774 is the percentage of IOU REP Settlement benefits attributable to non-Slice loads.

(4) PreliminaryUnconstrainedBenefits = InitialUnconstrainedBenefits + InitialIOU_DDC_Amount

(5) If PreliminaryUnconstrainedBenefits > 300 then
PrelminaryConstrainedBenefits = 300;
If PreliminaryUnconstrainedBenefits < 100 then
PreliminaryConstrainedBenefits = 100;
Otherwise, PreliminaryConstrainedBenefits =
PreliminaryUnconstrainedBenefits.

(6) FinalIOU_DDC_Amount = PreliminaryConstrainedBenefits – InitialConstrainedBenefits

Where FinalIOU_DDC_Amount is the amount by which the total IOU REP Settlement benefits for this year are to be increased from the amount calculated from the Forward Flat-Block Price (the market price in the WP-07 Final ROD for FY 2007, or the market price from brokers for FY 2008 and FY 2009), and the PF rate without the DDC from the WP-07 Final ROD.

(7) PF_DDC_Amount = DDC Amount – FinalIOU_DDC_Amount

(8) DDC Percentage = PF_DDC_Amount / DDC Revenue Basis

For products subject to the DDC, the DDC Percentage will be applied to HLH and LLH base energy rates for the twelve months beginning in October and ending the following September. The IOU Setttlement REP benefits and the DSI service benefits calculation will be adjusted if the benefits fall below the cap or rise above the floor.

The DDC Percentage cannot be so large that it reduces the LLH energy rate below $1.00/MWh.

2. DDC Adjustment Timing

Prior to the beginning of each fiscal year of the rate period, BPA will determine whether the forecast of the current fiscal year AMNR is above the DDC Threshold. If the AMNR is forecasted to be above the DDC Threshold, BPA will assess an adjustment to applicable rates for power deliveries beginning in October.

No later than September 30, BPA will notify customers of the calculated final DDC Percentage.

a. DDC Notification Process

BPA shall follow the following notification procedures:

(1) Financial Performance Status Reports

Each quarter, BPA shall post to its external website (www.bpa.gov), preliminary, unaudited, *year-to-date* aggregate financial results for generation function, including AMNR.

For the 2nd and 3rd Quarter Review, BPA shall post to its external website (www.bpa.gov), the preliminary, unaudited *end-of-year* forecast of AMNR attributable to the generation function.

(2) Notice of DDC Trigger

BPA shall complete a forecast of current fiscal end-of-year AMNR prior to the beginning of the next fiscal year. BPA shall notify all customers and rate case parties around mid-September, in each FYs 2006-2008 (prior to the beginning of the next fiscal year), if the expected value of AMNR is forecasted to be above the DDC Threshold for that fiscal year and, if so, the extent to which BPA intends to adjust rates due to the DDC. Notification will be posted on BPA's website, and will include the audited AMNR for the prior fiscal year, the forecast of end-of-year AMNR, the calculation of the Dividend Amount, and the forecast of the DDC Percentage. The notice shall also describe the data and assumptions relied upon by BPA. Such data, assumptions, and documentation, if non-proprietary and/or non-privileged, shall be made available for review by BPA upon request.

Prior to the end of each fiscal year, for any year in which the AMNR is forecasted to be above the DDC Threshold, BPA staff shall conduct a public forum to explain the AMNR forecast, the calculation of the Dividend Amount and the DDC Percentage, and to demonstrate that the DDC has been implemented in accordance with these GRSPs. The forum will provide an opportunity for public comment.

No later than September 30 of any fiscal year in which the AMNR is forecasted to be above the DDC Threshold, BPA will post to the BPA website the final calculation of the adjustment (as a percentage) to each product and benefit subject to the DDC as described above.

Proposed Dates in the WP-07 Rate Case

November 7, 2005	Federal Register Notice Published; *ex parte* begins
November 10, 2005	**Scheduling Conference**
November 21, 2005	BPA files Direct Case/Prehearing Conference & **Website Training**
December 5-9, 2005	Clarification
December 9, 2005	Data Request Deadline
December 9, 2005	Motions to Strike
December 15, 2005	Data Response Deadline
December 15, 2005	Answers to Motions to Strike
January 6, 2006	Parties file Direct Cases
January 17-20, 2006	Clarification
January 24, 2006	Data Request Deadline
January 24, 2006	Motions to Strike
January 30, 2006	Data Response Deadline
January 30, 2006	Answers to Motions to Strike
February 13, 2006	Close of Participant Comments
February 13, 2006	Litigants File Rebuttal Testimony
February 16-17, 2006	Clarification
February 17, 2006	Data Request Deadline
February 17, 2006	Motions to Strike
February 23, 2006	Data Response Deadline
February 23, 2006	Answers to Motions to Strike
March 6-17, 2006	Cross-Examination
April 14, 2006	Initial Briefs Filed
April 26-27, 2006	Oral Argument before Administrator
May 26, 2006	Draft ROD issued
June 9, 2006	Briefs on Exceptions
July 7, 2006	Final ROD—Final Studies

Public Field Hearings Schedule

• November 29, 2005	Springfield, Oregon
• November 30, 2005	Kalispell, Montana
• December 1, 2005	Spokane, Washington
• December 5, 2005	Idaho Falls, Idaho
• December 6, 2005	Tacoma, Washington
• December 7, 2005	Portland, Oregon

All hearings will be held 6:00 p.m. to 8:30 p.m. local time

WP-07 Power Rate Case Workshop

APPENDIX A

The material in this appendix represents updates from earlier workshops.

LOW DENSITY DISCOUNT (LDD)

BPA identified three potential changes to the LDD methodology at the August 9, 2005, informal rate case workshop. These changes involve: (1) revising the “Retail Rate to PF Rate” eligibility criterion, (2) changing “consumers” in the C/M ratio to “meters”, and (3) explicitly defining average retail rate. BPA will propose these changes in the Initial Rate Proposal.

As BPA reviewed the LDD methodology, it realized the General Rate Schedule Provisions (GRSPs) and the Block and Slice power sales agreement define the requirements portion of the Slice product differently. The difference between these definitions is important because the LDD benefits may differ. Therefore, BPA will propose changing the definition of the requirements portion of the Slice product in the GRSP’s to be consistent with the definition in the Block and Slice power sales agreement.

Rate Design

Changes in the calculation of the Load Variance charge from the 2000 Rate Case to the Initial Proposal for the 2007 Rate Case

What we did in 2000

- 2000 used historic data; this showed about 2% error in actual load compared to forecast loads and 2% load growth.
- Forecast error variations were positive and negative
- Load growth was valued using the value of put options (for negative deviations) and call options (for positive deviations)
- Approximately ½ of the total cost was load growth
- The total cost divided by total loads yielded a rate of $1.20/MWh
- In order to mitigate rate impacts, the charge was reduced to $0.80/MWh.

What we are proposing now

- Still using historic data, most recent 36 months
- These data shows about 2% error in actual load compared to forecast
- We used the forecast of load growth associated with the load forecast
- Call option pricing would be extremely high due to the current high market
- The delta from PF to market forecast is over $20/MW which is only part of the value of an option
- Put options would not be expensive but are never 0 or negative

Therefore we developed a new method

- Average historic forecast error was 2%
- Worst case would be to error on the low side in the forecast all the time and have to purchase all the time
- Market price minus PF was the delta used to value the 2% purchase in this scenario
- The cost to serve load growth was also the PF to market delta
- These together resulted in the new load variance charge of $0.53

Demand charge changes from 2000 to proposed 2007

What we did in 2000

- 2000 used hourly prices from Aurora
- The difference in positive hourly prices above annual average was summed for 5 years
- That total dollar amount was summed
- That was the total dollars to be recovered in the demand rate
- In retrospect, this charge over-collected relative to market prices
- In hindsight, staff believe that it collected costs for part of what the HLH energy charge was also collecting for – hence a double counting issue

2007 used hourly prices from Aurora

- We used quarterly average NOT annual average
- We used HLH only average NOT average of all hours

Why change to quarterly from annual average

- Backwardation in the market caused values in early months to increase demand
- Backwardation in the market caused values in late months to NOT increase demand
- This was a seasonal effect not intended to be valued in the demand charge
- Changing to quarterly averages removed this effect
- Changing to HLH average removed an effect of double counting the value of demand
- Because we believe some of the peaking value is captured in HLH energy
- This is not directly a capacity charge because this is ONLY sold with energy – you cannot buy a demand only product
- It is intended to recover some costs that may be due to high hourly energy rates
- Some capital costs are recovered in HLH energy rates
- The 2007 Demand Rate is $1.06/kW-month annual average

Rate Design

TAC and LLH Definitions

- BPA is proposing to exempt loads less than 1 aMW from the Targeted Adjustment Charge

- BPA is defining 6 holidays as LLH only; this change will also affect **TBL** definitions also; they are January 1, Memorial Day (observed), July 4th, Labor Day, Thanksgiving, and December 25th. If any of the days falls on a Sunday, then the next day (Monday) would be included in the LLH period